**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	**))))))))))**	**PROCEEDING NO. 16A-____E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF RUSSELL E. BORCHARDT</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

August 2, 2016

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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SUMMARY OF THE DIRECT TESTIMONY OF RUSSELL E. BORCHARDT

Mr. Russell E. Borchardt is Director, Business Operations of Xcel Energy Services Inc. ("Xcel Energy"). In this position, Mr. Borchardt is responsible for the operations and engineering of Xcel Energy's electric and gas metering organization for Xcel Energy, including Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy Inc. His duties include, among other things, providing direction, overall management, and technical expertise for the Meter Engineering, Performance & Standards and Field & Shop Metering areas. This includes oversight of gas and electric meter population performance; testing, installation and removal of meters; directing the development of metering standards and evaluation of metering technologies; and management of practices and policies related to metering.

In his testimony, Mr. Borchardt describes advanced metering infrastructure ("AMI"), which is a key component of Public Service's Advanced Grid Intelligence and Security ("AGIS") initiative. The AGIS initiative is a comprehensive plan that will make Public Service's electric distribution system more automated, resilient, and interactive by utilizing advances in sensing, controls, information, computing, communications, materials and components.

Specifically, Mr. Borchardt explains that AMI is an integrated system of advanced meters, communications networks, and data management systems that enable two-way communication between utilities' business and operational data systems and the meters themselves. Mr Borchardt explains how AMI meters present significant technological advancements over Public Service's current Automated Meter Reading ("AMR") system, which consists of meters equipped with one-way communication modules. With AMR, billing data alone is transmitted to a drive-by van that collects the limited data for later download to the Company's business and customer billing systems. In addition to automating meter reading and the transmission of data to Company systems via two-way communication, AMI meters have the ability to provide greater insight into customers' own energy usage, better outage information and response time, and more efficient distribution system management.

In addition to describing these technologies and the need for them, Mr. Borchardt describes Public Service's implementation plan for these technologies. Mr. Borchardt also discusses the cost of AMI as well as its many benefits, including in the areas of distribution system management, outage management efficiency, avoided meter purchases, avoided meter reading costs, avoided field and meter service costs, improvements in customer care, distribution management and outage management savings, reduction in energy theft, reduced consumption on inactive premises, reduced uncollectible and bad debt expense, and customer outage reductions. The qualitative benefits of AMI include improved customer choice and experience, enhanced distributed energy resource integration, environmental benefits associated with enhanced energy efficiency, improved safety to both customers and Public Service employees, and improvements in power quality. Finally, Mr. Borchardt discusses why alternatives to implementing AMI do not displace the public convenience and necessity of AMI for Public Service customers.

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DIRECT TESTIMONY AND ATTACHMENTS OF RUSSELL E. BORCHARDT

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
BPL	Broadband over Power Line
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CIS	Customer Information System
CMO	Customer Minutes Out
Commission	Colorado Public Utilities Commission
Company	Public Service Company of Colorado
CPCN	Certificate of Public Convenience and Necessity
CPCN Projects	AMI, IVVO, and the components of the FAN that support these components
CPE	Customer premise equipment
CRS	Customer Resource System
CSF	Cyber Security Framework
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DDOS	Distributed Denial of Service
DER	Distributed Energy Resources
DOS	Denial-of-service
DR	Demand Response
DSM	Demand Side Management
DVO	Distribution Voltage Optimization
EPRI	Electric Power Research Institute
ERT	Encoder Receiver Transmitter
ESB	Enterprise Service Bus
FAN	Field Area Network
FLISR	Fault Locate Isolation System Restoration

Acronym/Defined Term	Meaning
FLP	Fault Location Prediction
GFCI	Ground Fault Circuit Interrupter
GIS	Geospatial Information System
HAN	Home Area Networks
ICE	Interruption Cost Estimation
IDS	Intrusion Detection System
IEEE	Institute of Electrical and Electronics
IPS	Internet Provider Security
IT	Information technology
IVR	Interactive Voice Response
IVVO	Integrated Volt-VAr Optimization
kVAr	Kilovolt-amperes reactive
kVArh	Reactive power
kW	Kilowatt
kWh	Kilowatt hours
LTCs	Load Tap Changers
LTE	Long-Term Evolution
MDM	Meter Data Management
MitM	Man-in-the-Middle Attack
MPLS	Multiprotocol Label Switching
NCAR	National Center for Atmospheric Research
NOC	Network Operations Center
NPV	Net Present Value
O&M	Operations and Maintenance
OMS	Outage Management System
OT	Operational Technology
PTMP	Point-to-multipoint
Public Service	Public Service Company of Colorado
RF	Radio frequency
RFP	Request for Proposal
RFx	Request for Information and Pricing
RTU	Remote Terminal Units

Acronym/Defined Term	Meaning
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGCC	Smart Grid Consumer Collaborative
SGIG	Smart grid investment grants
SIEM	Security Incident and Event Management
SVC	Secondary static VAr compensators
TOU	Time-of-use
USEIA	United States Energy Information Administration
WACC	Weighted Average Costs of Capital
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	802.15.4g Standard
Xcel Energy Inc.	Xcel Energy
XES	Xcel Energy Services Inc.

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RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	**))))))))))**	**PROCEEDING NO. 16A-___E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF RUSSELL E. BORCHARDT</u>

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Russell E. Borchardt. My business address is 1518 Chestnut Avenue North, Suite 100, Minneapolis, Minnesota 55403.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Director, Business Operations. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Director, Business Operations, I am responsible for the operations and engineering of Xcel Energy's electric and gas metering organization, which includes Public Service. My duties include providing direction, overall management, and technical expertise for the Meter Engineering, Performance & Standards and Field & Shop Metering areas. This includes oversight of gas and electric meter population performance; testing, installation and removal of meters; directing the development of metering standards and evaluation of metering technologies; and management of practices, procedures, and policies related to metering. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In my testimony, I describe advanced metering infrastructure ("AMI"), support the need for this technology as part of bringing the Public Service distribution grid into the future, identify the costs and benefits of AMI implementation, and explain the alternatives to AMI that Public Service has considered.

AMI, as well as the Company's proposed Advanced Distribution Management System ("ADMS"), the Field Area Network ("FAN"), the Integrated Volt-VAr Optimization ("IVVO") function, and the Fault Location Isolation and Service Restoration ("FLISR") function including the Fault Location Prediction ("FLP") component, are critical parts of the Company's Advanced Grid Intelligence and Security ("AGIS") initiative. The AGIS initiative is a comprehensive plan that will advance Public Service's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS will lay the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future. A more thorough discussion of Public Service's AGIS initiative and the request to approve the Company's Certificate of Public Convenience and Necessity ("CPCN") Application is provided in the Application and in the Direct Testimonies of Company witnesses Ms. Alice K. Jackson and Mr. John D. Lee.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. In my Direct Testimony, I:

- Provide a brief overview of AMI, including a description of AMI meters, which are included in the Company's CPCN Application in this proceeding ("CPCN Projects Application"). AMI meters measure, store and transmit metering quantities, including energy usage information at a customer level, among other capabilities described in detail in my testimony. AMI meters use a radio frequency communication module to provide two-way communication between the AMI meter and the Company.
- Discuss how AMI will interact with other aspects of proposed infrastructure to provide customer benefits, including greater insight into their own energy usage, better outage information and response time, and more efficient distribution system management.

- Explain that AMI is current industry technology and underscore why it is important for the Company to implement AMI technology now.
- Describe the timeframe for AMI deployment.
- Discuss the quantifiable benefits that were used as inputs in the cost-benefit analysis ("CBA") in this proceeding, along with the qualitative benefits AMI brings to customers and the Company. I also discuss in detail the costs that are related to AMI that were used in the CBA.
- Address the possible alternatives to AMI that the Company considered.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following:

- Attachment REB-1: AMI Quantifiable Benefits Summary
- Attachment REB-2: AMI Costs Summary

II. AMI TECHNOLOGY

Q. WHAT IS PUBLIC SERVICE'S AGIS INITIATIVE?

A. As described in more detail in the CPCN Projects Application, in the Direct Testimonies of Company witnesses Ms. Jackson and Mr. Lee, and in my Direct Testimony with respect to AMI, AGIS is a comprehensive plan to advance Public Service's distribution system to a state where (1) operators have more visibility into the system; (2) customers are able to access more information near real-time; and (3) future products and services are enabled through technology. AGIS will help to bring about an intelligent, automated, and interactive electric distribution system that will utilize advances in sensing, controls, information, computing, communications, materials and components to optimize the performance of the electric distribution system and ensure safe operation. The more intelligent distribution system will be able to better meet customers' energy needs, while also integrating new sources of energy and delivering power over a network that is increasingly interoperable, efficient, and resilient.

As Company witnesses Ms. Jackson and Mr. Lee also discuss, the CPCN Projects Application is seeking approval of the AMI and IVVO components of AGIS, as well as the associated components of the FAN.

Q. WHICH COMPONENT OF THE CPCN PROJECTS WILL YOU DISCUSS IN YOUR TESTIMONY?

A. As noted above, I will discuss AMI and explain how advanced meters will interact with the other foundational programs of the AGIS initiative.

A. Overview of AMI

Q. WHAT IS AMI?

A. Advanced Metering Infrastructure is an integrated system of advanced meters, communications networks, and data management systems that enable two-way communication between utilities' business and operational data systems and meters enabling added benefits for customers and the utilities.

Q. HOW IS THIS DIFFERENT THAN WHAT PUBLIC SERVICE HAS TODAY?

A. Public Service has an Automated Meter Reading ("AMR") system in place today. AMR at Public Service consists of meters equipped with one-way communication modules that transmit meter readings to a drive-by van that collects the meter data for later download to the Company's business and customer billing systems. The function of AMR is the collection of meter readings for billing purposes, whereas AMI meters have the ability to enable additional operational functions and customer benefits in addition to collecting meter billing reads.

Q. PLEASE DESCRIBE ADVANCED METERS.

A. Advanced meters are the key endpoint component of an AMI system that measures, stores and transmits metering quantities, including energy usage information at customer locations.

Q. PLEASE DESCRIBE THE COMPONENTS OF AN ADVANCED METER.

A. The components of an advanced meter include (i) the meter itself, (ii) a two-way radio frequency communication module, and (iii) an internal service switch.

Q. CAN YOU DESCRIBE THE FUNCTION OF THE ADVANCED METER ITSELF?

A. Yes. The advanced meters can be remotely configured to measure bi-directional and/or time-of-use ("TOU") energy consumption in kilowatt hours ("kWh") and demand in kilowatts ("kW"). A meter that is configured for bi-directional energy measurement measures energy provided from the Company to the customer and also measures energy provided from the customer to the Company. Net metering for a solar customer is an example of metering with bi-directional functionality. The consumption of kWh/kW can be recorded by the advanced meter in intervals as short as five or 15 minutes, or longer intervals if desired.

Additionally, advanced meters have the capability to:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events; and,
- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and the communications module.

Q. HOW ARE THE AMR METERS PUBLIC SERVICE HAS TODAY LESS CAPABLE THAN AN ADVANCED METER?

A. The AMR meters have a number of limitations as compared to AMI-capable meters, which I describe in the bullet points below.

- AMR meters have fixed, basic metering functions and are purchased with two different communication module types. One type of communication module is limited to enabling the transmission of meter readings for either energy delivered or net energy measured by the meter. The second type of communication module enables transmission of bi-directional (delivered and received) that is limited to energy meter readings or delivered energy and demand (KW) meter readings. AMI meters are programmable to meter these energy parameters as well as flexible time of use schedules, reactive energy (kilovolt ampere reactive hours/kilovolts ampere reactive ("kvarh/kVAr") quantities, and various load profile interval choices.

- The AMR meters do not have interval data (load profile) recording capability. If interval data recording is required, the AMR meter is exchanged with a non-AMR meter that has that functionality and it is either manually read or equipped with a modem for remote reading.
- Public Service's current AMR meters do not support residential TOU measurements. The Company presently does not have a residential TOU rate, however, there is a proposed TOU tariff in the Company's Phase II filing (Proceeding No. 16AL-0048E). With the proposed TOU rate, to stay with AMR metering it will be necessary to implement a meter exchange with a different meter type and AMR communications module type that will provide TOU readings and load profile functionality compatible with the existing drive-by AMR system. Although this process would enable the customer to take advantage of time based rates, it only provides monthly meter readings and does not provide the timely data needed to support the ADMS and IVVO components of AGIS.

- Public Service's AMR meters are not capable of measuring and transmitting voltage, current, power quality data, meter diagnostic, or power outage and restoration events.
- AMR meters provide only one set of meter readings per month collected by a drive-by van and cannot provide an on-request or off-cycle meter reading without rolling a truck.
- The AMR meters do not have an internal service switch to provide remote connection of service.
- AMR meter firmware cannot be upgraded remotely.

Q. IN CONTRAST, CAN YOU DESCRIBE OPERATIONAL BENEFITS OF THE AMI SYSTEM OVER PUBLIC SERVICE'S EXISTING AMR SYSTEM?

A. Yes. As described in detail in the Direct Testimony of Company witness Mr. Wendall A. Reimer and in more detail below, AMI meters have multiple paths to transmit the data collected via the mesh communication network (a portion of the FAN) to the AMI head-end application. As a result, if one AMI meter communication path fails, an alternate path is found by using a different AMI meter as a repeater. Additionally, AMI meters will collect and transmit data to the Company's head-end application a minimum of six times per day, every four hours, providing operational improvements over AMR for collecting customer bill reads and minimizing the need for estimated bills. If there is an obstruction of the radio frequency between the meter and the truck during the drive-by meter reads once a month, the current AMR system cannot rad the meter and the customer will receive an estimated bill for that billing month.

Q. CAN THE METERS TRANSMIT DATA MORE FREQUENTLY THAN EVERY FOUR HOURS?

A. Yes. There are a several scenarios where the meters will communicate to the head-end software application more often than every four hours.

- Public Service plans to build a customer internet portal through the Information Technology ("IT") integration of the AGIS initiative components. Through this portal, the customer could initiate an on-demand meter reading to the customer's meter. When the on-request read is completed, the customer's portal will be updated with the latest near real-time energy information. The customer will have the ability to access and refresh the meter data through the portal as often as desired. Similar capabilities will be provided in a smartphone application.
- Meters selected along the distribution feeders to provide data to ADMS will be configured for five minute interval data, and will transmit data to the head-end application every five minutes and make it available to ADMS. The interaction between AMI and ADMS is described in more detail in the next section of my Direct Testimony.
- Groups of meters may be placed on ad-hoc or regularly scheduled read requests. These groups could be the total meter population to be read daily, weekly, or monthly at a specified time of day. The groups of meters may also be subsets of the meter population read at specified intervals, such as a billing cycle meter read.

- An individual meter may be read on an on-request basis. For example, a customer care employee may collect the meter data while on the phone assisting a customer.
- The meters will transmit data when an event occurs such as a power outage or power restoration, power quality event, diagnostic event, reconfiguration or upgrade occurrence, or operation of the internal service switch. The transmitted data included as a result of these events will be dependent on the specific event.

Q. TURNING TO THE SECOND COMPONENT OF AN ADVANCED METER, CAN YOU DESCRIBE THE FUNCTION OF AN ADVANCED METER'S TWO-WAY RADIO FREQUENCY MODULE?

A. Yes. The radio frequency communication module will utilize the Company's communications network, as described in the Direct Testimony of Company witness of Mr. Reimer, to provide two-way communication between the meter and the AMI head-end application, which is the operating software system that is used to send data requests and commands to an advanced meter, and receive data from an AMI capable meter. Such communications include:

- Transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- Receiving commands from the head-end application to send specific meter measurements, alarms and events, reset demand registers, configure the meter to measure specific sets of energy parameters or time of use intervals and data recording intervals and channels;

- Remotely performing meter firmware upgrades; and
- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Additionally, the AMI meter's communication module can act as a two-way repeater for other advanced meters on the communication network.

Q. CAN YOU DESCRIBE THE FUNCTION OF AN ADVANCED METER'S THIRD COMPONENT, THE INTERNAL SERVICE SWITCH?

A. The internal service switch remotely connects or disconnects power to the customer's electric service upon command from the head-end data application. The internal service switch is available on 200 ampere single-phase AMI meters, which includes the residential and small commercial customers in the Company's service territory.

B. AMI as Part of the AGIS Infrastructure

Q. WILL THE ADVANCED METER INTERACT WITH OTHER AGIS INFRASTRUCTURE AND TECHNOLOGIES?

A. Yes. The advanced meter will utilize the communication network to transmit the information it gathers. Then that information will be available to the Company through the head-end software application. In addition to providing customer energy usage information, the AMI meter will provide information that will assist with service outages and restoration. The advanced meter will also provide voltage measurement information to assist in load flow and voltage calculations performed by the ADMS. Additionally, as stated earlier advanced meters can serve as a repeater for other advanced meters or mesh network components. I explain these concepts in more detail below.

Q. WHAT IS THE ADVANCED DISTRIBUTION MANAGEMENT SYSTEM?

A. The ADMS is a collection of hardware and software applications designed to monitor and control the entire electric distribution system safely, efficiently and reliably. The ADMS is discussed in more detail in the Direct Testimony of Company witness Mr. Chad S. Nickell.

Q. HOW WILL AMI INTERACT WITH ADMS?

A. AMI will provide the ADMS with timely real and reactive power measurement data that will be used in load flow and Integrated Volt-VAr Optimization ("IVVO") calculations. AMI meters will also provide voltage measurements at various points on the distribution system to support IVVO calculations. As Company witness Mr. Nickell discusses in his Direct Testimony, together this information will allow the Company to reduce overall voltage on the system resulting in customer savings.

Additionally, advanced meters will report a power-out or "last gasp" event to the AMI head-end application and report a power-on event when power is restored. "Last gasp" is defined as the final message transmitted by the meter upon detection of an outage. This information will flow from the head-end application into ADMS, improving the calculations for the fault location and restoration applications.

Q. WHAT IS THE FIELD AREA NETWORK?

A. The FAN is a multi-tiered communication network that will enable communications between the Company's existing substations and field devices, such as AMI meters. The FAN is discussed in more detail in the Direct Testimony of Company witness Mr. Reimer.

Q. HOW WILL THE AMI METER INTERACT WITH THE FAN?

A. The AMI meter's two-way communication module is a component of the mesh network layer of the FAN, which is the component of the FAN included in the CPCN Projects. The mesh network is based on Institute of Electrical and Electronics Engineers ("IEEE") 802.15.4g standard, sometimes known as a Wireless Smart Utility Network ("WiSUN"). The communication module retrieves meter data that is stored within the meter as prescribed by ANSI C12.19 meter table implementation standards. That data is then transmitted over the mesh network to an access point device that transitions the data from the mesh network to the Worldwide Interoperability for Microwave Access ("WiMAX") tier of the FAN and then to the Public Service Wide Area Network ("WAN") for data backhaul. In limited circumstances where deployment of the WiSUN mesh network is not practical (such as remote locations on the edge of Public Service's distribution system), meter data may be transmitted over the FAN via public cellular or other wireless technologies.

The radio frequency communications modules in the meters may also act as a repeater for other mesh network devices, enabling two-way communication between the meters and the mesh network. This function has the benefit of increased reliability of communication between the AMI meters and the head end application. If the communication signal is weak between an AMI meter and the access point device, the meter may have a stronger communication path to the access point by having another meter (or number of meters), act as a repeater. In a mesh network, if an AMI meter that is acting as a repeater fails, is removed, or has its communication signals blocked, the downstream AMI meters will recognize that their communications path has been interrupted and will search for and establish another communications path to the access point device. This is often referred to as a "self-healing" function of a mesh network. The robustness of the FAN mesh network is determined by the density of deployed field mesh devices, and the embedded communication modules in the meters make this possible. This is described in more detail in the Direct Testimony of Company witness Mr. Reimer.

Q. WHY DOES AMI NEED THE FAN IF IT CAN OPERATE OVER CELLULAR AND OTHER WIRELESS TECHNOLOGY?

A. The mesh technology proposed is a widely-implemented AMI technology that has proven to be a cost effective, reliable, and secure network technology. In contrast, utilizing public cellular solutions would require Public Service to deploy a cellular modem in every single meter and pay monthly fees for usage and for the private internet protocol service for every device. This alternative would cause the Company to incur substantial monthly and annual expenses.

Another significant AMI advantage of a Company-owned FAN is security. A private network allows Public Service to better control the integrity of the devices on its network and the data exchanged with those devices. The alternative, a public network, would expose the devices and Public Service to increased risk because the Company would not be in control of the network.

In addition, the private network solution allows Public Service to utilize the network's full bandwidth and all capacity is dedicated to the Company's use, which is critical during emergency and outage situations.

A private mesh network will also afford the AMI meters the ability to communicate directly with one another on the WiSUN standards-based network. This will enable future distributed intelligence and computing capabilities so that applications running on the system will be able to respond quickly to changing load conditions that occur behind a transformer. This is becoming increasingly critical to energy operations as a larger number of distributed energy resources connect to the distribution grid. Cellular or other wireless technologies may be required where the density of meters and distribution devices is not sufficient to sustain a mesh network or where there are more feasible solutions for data back-haul than the WiMAX communication layer.

Q. WHY ARE BOTH WiMAX AND WiSUN NEEDED?

A. The WiSUN communication layer of the FAN is the mesh network that allows a meter to communicate directly to an access point device or relay its data through another meter's communication module to access point device. The access point device on the mesh network collects data from a cluster of meters on the mesh network. The meters with their embedded communication modules make up the majority of devices on the mesh, or WiSUN, network. The WiMAX layer serves to provide connectivity between the WiSUN mesh network and the Company's WAN to back-haul the data from the collection device to the Company's business system applications.

Q. WHAT IS FAULT LOCATION ISOLATION AND SERVICE RESTORATION ("FLISR")?

A. Fault Location Isolation and Service Restoration ("FLISR") is an application that involves deploying automated switching devices with the objective of decreasing the duration and number of customers affected by an individual outage. Fault Location Prediction ("FLP") is a subset application of FLISR that leverages sensor data from field devices to locate a faulted section of a feeder line. FLISR and FLP are discussed in more detail in the Direct Testimony of Company witness Mr. Nickell.

Q. HOW WILL THE AMI METER INTERACT WITH FLISR AND FLP?

A. The last gasp and power-on outage information that advanced meters will provide will be available to the ADMS. In turn, the ADMS will result in a more accurate model and forecasting tool for FLP and FLISR. As Mr. Nickell discusses in more detail, these interactions enable the Company to more precisely locate faulted sections of feeders, which reduces patrol times, and to improve FLISR switching plans, which minimizes the outage impact to customers.

Q. WHAT IS IVVO?

A. As mentioned above, IVVO stands for Integrated Volt-VAr Optimization, which is an advanced function that automates and optimizes the operation of the distribution voltage regulating devices and VAr control devices to reduce distribution electrical losses, reduce electric demand, reduce energy consumption, and increase capacity to host distributed energy resources. IVVO is discussed in more detail in the testimony of Company witness Mr. Nickell.

Q. HOW DO AMI METERS IMPACT VOLTAGE OPTIMIZATION?

A. As discussed earlier in my testimony, an advanced meter provides voltage information to ADMS from strategic points on the grid, which is ultimately used by the IVVO application to regulate voltage levels on the grid. More specifically, voltage measurements from the AMI meters will be transmitted over the FAN to the AMI head-end application, and then to ADMS through an interface between ADMS and the AMI head-end application, with measurements provided at pre-determined intervals for data collection and processing. The ADMS uses that information to calculate voltage levels at all points on the grid, with improved accuracy. Those calculations are used by the IVVO application to operate the voltage control devices on the grid, optimizing the voltage levels on the grid while keeping the voltage within proper limits at all points on the grid.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE ROLE OF AMI IN THE OVERALL AGIS INITIATIVE?

A. As described above, advanced metering is a central source of information with which virtually all components of an intelligent grid design interact. AMI technology is also critical to support certain benefits of the AGIS initiative, including the possibility for time of use rates and the associated price signals, more efficient distribution system management, and greater customer control over energy usage.

C. <u>AMI Industry Adoption</u>

Q. IS PUBLIC SERVICE'S PROPOSAL FOR AMI METERS CONSISTENT WITH INDUSTRY TRENDS?

A. Yes. According to the United States Energy Information Administration ("USEIA"), in 2013 the number of installed AMI meters (53.3 million) surpassed the number of installed AMR meters (47.3 million) in the United States.[1] Moreover, the USEIA's statistics indicate that the number of installed AMI meters increased from 20.3 million meters in 2010 to 58.5 million meters in 2014. Based on our review of the data reported to USEIA, peer utilities around the country, such as Florida Power and Light Company (a subsidiary of NextEra Company), Georgia Power Company (a subsidiary of Southern Company), and Pacific Gas & Electric Company, have already installed AMI meters. Additionally, many utilities like Public Service that implemented AMR systems already have converted to AMI.

Q. WHY IS IT IMPORTANT TO IMPLEMENT AMI NOW?

A. As described in more detail in the Direct Testimony of Company witnesses Mr. Lee and Ms. Jackson, the current system does not provide us with the necessary visibility into the electric distribution grid. Upgrading to AMI will also allow Public Service to provide more reliable and efficient service to meet the growing

[1] Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

expectations of customers. AMI meters will do that by providing frequent, timely information of actual load and system conditions as well as information for billing purposes. Providing this level of information is not possible through the once-per-month reading of AMR meters, which do not have the functionality to achieve the benefits of AGIS described throughout the CPCN Projects Application and supporting testimony.

Additionally, the Company's AMR technology was installed in the mid-1990's and is an aging technology. While the AMR technology the Company uses is still supported by some vendors, Aclara, which was formerly General Electric, has chosen to discontinue selling these AMR meters. Additionally, Landis+Gyr, another established meter vendor, has eliminated the production of certain AMR meters. Public Service believes this trend will continue with other vendors, making it increasingly difficult to support AMR meters.

Finally, the growth of distributed energy resources creates a need to have timely load flow information and voltage monitoring on the Company's distribution system beyond the substation level in order for the Company to more accurately monitor the power flow on the grid. AMI will provide data in these areas to assist in providing reliable and quality service to our customers.

Q. WHY DOESN'T THE COMPANY REPLACE AMR METERS WITH AMI AT THE END OF THE AMR METERS' DESIGN LIFE OR AS THEY FAIL?

A. The AMI mesh technology Public Service proposes requires some density of meters or devices to make up and sustain communications. As explained above, the AMI meters communicate within a mesh to an access point device, and the data is then back-hauled to the Company's head-end application. If we were to replace AMR meters as they reach end of life or as they fail, we would still need the access point devices and the WiMAX layer of the FAN in place at that time. Additionally, we would need to replace a number of meters within the surrounding area of the end of life or failed AMR meter to make up a successful mesh network. Installing AMI in this fashion would delay realizing the benefits of a fully deployed AMI.

D. <u>Information Technology and Cyber Security</u>

Q. WILL THE INSTALLATION AND DEPLOYMENT OF AMI METERS BE INTEGRATED WITH THE COMPANY'S EXISTING INFORMATION TECHNOLOGY?

A. Yes. The advanced meters will be integrated with the Company's information technology system. AMI is data intensive with meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data from the meters comes into the head-end application and, depending on what the data is, needs to be integrated and made available to the applicable business system in an accurate and timely manner. IT integration is explained in more detail in the Direct Testimony of Company witness Mr. David C. Harkness.

Q. WILL THE COMPANY UNDERTAKE CYBER SECURITY MEASURES ASSOCIATED WITH THE INSTALLATION OF AMI METERS?

A. Yes. Although no personal customer information is transmitted, the confidentiality and integrity of the data is very important to the Company, and the safe, secure, and reliable operation of the grid is critical. The Company's cyber security measures are explained in more detail in the Direct Testimony of Company witness Mr. Harkness.

III. AMI METER IMPLEMENTATION

Q. WHERE IS THE COMPANY PLANNING TO DEPLOY AMI METERS?

A. AMI meters will be installed at nearly every meter location in the Company's service territory where electric energy is supplied to end-use retail customers, allowing those customers to benefit from AMI meters. Today we have approximately 1.40 million meters on our system. However, with projected growth we anticipate installing approximately 1.5 million meters over the project timeframe of 2018 – 2021.

Q. WHAT PRELIMINARY WORK HAS THE COMPANY PERFORMED IN PREPARATION FOR AMI DEPLOYMENT?

A. A cross functional team of employees from multiple business areas developed the customer and Company requirements of an AMI system, including both hardware and software needs, and associated AGIS initiatives such as FAN, ADMS, and IVVO. The business and IT areas that were represented on the team included Meter Performance and Standards, Sourcing Services, Distribution Engineering, Business Solutions, Customer Care, Telecommunications Engineering, and Enterprise Architecture. As discussed later in this testimony, the Company issued a Request for Information and Pricing ("RFx") related to AMI, the FAN, and distribution automation. Vendor response information from the RFx was used to develop the cost inputs that were used in the cost benefit analysis, which is discussed in the Direct Testimony of Company witness Mr. Samuel J. Hancock.

Q. WHAT IS THE AMI DEPLOYMENT TIMELINE?

A. The request for proposal ("RFP") for the selection of an AMI vendor was sent in mid-July 2016 to the same potential vendors that responded to the Company's RFx. The Company currently anticipates that a vendor will be selected in November of 2016. After the AMI vendor is selected, a contract will be executed and the required design, development, and integration work of business systems will begin. Additionally, deployment teams and field logistics will be put into place. Depending in part on the timing of Commission approval as well as implementation of vendor contracts, Public Service's currently plans to install the first AMI meter during the fourth quarter of 2018. By the end of 2020, it is anticipated that approximately 95% of the meter installations will be complete.

The sequencing of specific meter exchanges has not yet been fully developed, but we anticipate completing the Denver metro area before moving to the more rural geographic areas. Locations and timing of AMI meter deployment will be dependent on the FAN being in place prior to a meter exchange. With an operational FAN in place, communication to the AMI meters can be established as they are installed.

Q. WHY ARE METER DEPLOYMENTS EXPECTED TO BEGIN IN 2018?

A. It is critical to complete IT work between vendor selection and meter deployment to ensure customer billing continuity. The primary role of the meter will still be to accurately measure the customers' energy consumption (or generation) and ultimately provide billing accuracy data to the Company's customer billing system. IT work will help ensure customer accounts and billings are accurate and are not interrupted as meter exchanges occur.

Q. HOW WILL AMI AND ADVANCED METERS BE INSTALLED?

A. The exchange of AMI meters in the field will be performed by qualified employees or contractors under the management and direction of the Company.

Q. HOW LONG WILL EACH METER EXCHANGE TAKE?

A. The time to exchange each meter will vary by the type of service and meter that each customer has, but in most cases the meter exchange for a residential customer should take less than 15 minutes.

Q. WHY IS THE COMPANY CHOOSING TO REPLACE ALL ELECTRIC METERS?

A. The Company is choosing to install the 1.5 million electric meters to enable the Company to offer or provide associated customer-related AMI benefits to all customers. The proposed AMI technology requires the meters to be installed in clusters to form a reliable mesh network. While these clusters could in theory be installed in a subset portion of the Company's service territory or based on customer type (such as commercial and industrial versus residential), the overall benefits of AMI will not be available to all Public Service customers if we only replace AMR meters for a subset. Additionally, other AGIS components, like IVVO, would receive voltage measurement data only in the areas that AMI advanced meters were installed, instead of system-wide.

IV. BENEFITS AND COSTS

A. Benefits

Q. WHAT TYPES OF BENEFITS DOES PUBLIC SERVICE ANTICIPATE ACHIEVING FROM AMI INSTALLATION?

A. From a capital perspective, Public Service anticipates quantifiable capital savings in the areas of distribution system management, outage management efficiency, and avoided meter purchases. With respect to operations and maintenance ("O&M"), Public Service anticipates quantitative reductions in the categories of meter reading costs, field and meter service costs, improvements in customer care, as well as distribution management and outage management savings. We also anticipate some savings with respect to reduction in energy theft, reduced consumption on inactive premises, reduced uncollectible and bad debt expense, and customer outage reductions. Finally, Public Service anticipates a number of benefits that are not readily quantifiable. I address each of these benefits below.

1. Capital Benefits

Q. PLEASE DESCRIBE THE DISTRIBUTION SYSTEM MANAGEMENT BENEFITS THAT CUSTOMERS WILL RECEIVE FROM AMI.

A. Distribution System Management benefits from AMI are primarily capital benefits that customers will realize beginning in 2020, when we have installed a critical mass of AMI meters. AMI data can be aggregated at varying levels of the distribution system that include the tap, transformer, and service lines amongst other distribution system equipment. This data will be used to prioritize distribution grid improvements and more efficiently plan and design the system.

This data can then be used to determine optimum installation and replacement of distribution assets as well as optimizing inventory level. The Company has estimated that a 1% capital benefit will be achieved in reducing capital expenditures through more efficient installation and replacement of distribution assets related to reliability and capacity projects. The Company's 1% estimated benefit is in alignment with the Ameren Illinois AMI Business Case. The inputs that make up the approximate $2.2 million of distribution system management ("DSM") benefits in years 2020 and 2021 were calculated by taking average annual Public Service capital budgets over the five-year period of 2016 through 2020.

Q. PLEASE DESCRIBE THE BENEFITS FOR OUTAGE MANAGEMENT EFFICIENCY THAT WILL BE ACHIEVED WITH THE INSTALLATION OF AMI METERS.

A. AMI will enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System ("OMS"). Power loss information is identified by an AMI meter's last gasp. Outage notification from the AMI meters will provide the Company with a more timely and accurate scope of an outage without relying on customers to report an outage. The restoration confirmation available from AMI also enables the Company to focus and optimize its restoration efforts on active outages, minimizing field trips where outages do not exist, also known as "Okay on Arrival" outage calls. The automated outage information provided by the AMI meters will then assist the

Company in restoring power more quickly because the Company will no longer be dependent upon the customer notifying the Company of a power loss. Overall, because of these increased outage management efficiencies, AMI enables quicker response and restoration to customer outages to minimize inconveniences or economic losses that could be experienced by the customer.

Q. HAS PUBLIC SERVICE ESTIMATED THE MONETARY VALUE OF THESE BENEFITS?

A. Yes. Public Service expects to begin realizing financial benefits from greater outage management efficiency in 2019. The Company benchmarked this benefit against Ameren Illinois, and estimates that AMI will contribute a 10% efficiency gain from storm-related capital costs. The yearly capital benefits that make up the outage management efficiency estimate identified in Attachment REB-1 proportionally take into account the number of AMI meters cumulatively installed in years 2019 through 2021 and use the Company's average annual storm-related capital cost ($1,053,833) over years 2014 and 2015, $560,890 and $1,546,776 respectively, to arrive at the 10% quantified benefit of $105,383 to be achieved when all AMI meters are installed in 2021. The yearly O&M benefits that make up the outage management efficiency estimate identified in Attachment REB-1 also proportionally take into account the number of AMI meters cumulatively installed in years 2019 through 2021 and use the Company's average annual storm-related O&M cost ($1,118,918) over years 2014 and 2015, $372,370 and $1,865,465 respectively, to arrive at the 10%

quantified benefit of $111,892 to be achieved when all AMI meters are installed in 2021.

Q. HOW DID YOU ESTIMATE THE VALUE OF AVOIDED METER PURCHASES?

A. The estimated benefit of avoided meter purchases was derived by comparing costs of a “business as usual” scenario, which includes business operations with existing installed meters, to the costs of implementing a new AMI meter population. Under the business as usual scenario, the Company would continue to replace and retire meters due to failures, performance, and age at projected costs. The AMI meter scenario assumes replacing the existing meters with a lower meter retirement rate. The total benefit of $7.8 million over the years 2019 through 2021 identified in Attachment REB-1 is based on a historical annual meter replacement retirement rate of 3.3% for current electric meters. The AMI scenario used an estimated failure rate of 0.5%; an estimated meter growth rate of 1.56%; and a labor escalator of 2.0%.

B. O&M Benefits

Q. WILL CUSTOMERS REALIZE A BENEFIT IN THE REDUCTION OF METER READING COSTS?

A. Yes. The estimated benefits in Attachment REB-1 for Reduction of Manual Meter Readings Expenses and Reduction in On-Cycle Meter Reading Vehicle Expenses are estimated to be realized through the elimination of contracted manual meter reading and the reduction of 31 full-time-equivalent headcount and their associated fleet costs specific to meter reading. Our goal is to reduce headcount through position reassignments and expected retirements.

Q. DOES PUBLIC SERVICE EXPECT THAT CUSTOMERS AND PUBLIC SERVICE EXPERIENCE BENEFITS FROM A REDUCTION IN NECESSARY FIELD AND METER SERVICES?

A. Yes. AMI meters equipped with internal service switches can be operated remotely, minimizing disruptions to the customer by a physical customer visit. Additionally, the use of the switch enables timelier connection or disconnection of service at the customer's convenience. The Company anticipates reducing the need to deploy personnel to manually connect or reconnect customers, or to take special meter readings at customer premises. Because meters will be able to be controlled remotely, Public Service also anticipates reduced consumption on inactive premises and reductions in the Company's incurrence of uncollectible expenses and debts.

We estimate that these capabilities will benefit the Company through a reduction in O&M costs beginning in 2019, in the following areas:

- **<u>Reduction in manual disconnection and reconnection of meters:</u>** Based on the Company's 2015 completed electric disconnects and reconnects of residential meters for reasons including credit, customer requests, and revenue assurance, we estimate a reduction of approximately 90% of manual disconnections and reconnections through remote capabilities. This equates to an annual reduction of approximately 63,800 manual disconnections and reconnections of meters. Although this estimate was benchmarked with Ameren Illinois, Ameren's business case was unclear on the estimated percentage benefit. The Company believes there may be instances where disconnect or reconnect commands will not be successful or not confirmed as successful, and some manual orders may be needed. Manual disconnections may also be necessary where a customer does not have a telephone number on record or the number has been disconnected.

- **Reduction in manual off-cycle and special meter reads:** Based on the Company's 2015 data associated with manual off-cycle and special meter reads, the Company estimates an annual reduction in nearly all of these types of manual reads, approximately 450 annually at an internally estimated cost of $4.00 per reading.. This benefit will be realized in 2019 through 2021 proportionate to the number of AMI meters installed reaching he full annual benefit of $1,800 in 2021
- **Reduction in nuisance stopped meter orders:** These are meter exchange orders that are system-generated because there was no energy consumption on the meter since the last billing meter reading. These orders may also be system-generated because the energy consumption reported is lower than expected as compared to Company-established data validation criteria for high or low consumption. In either of these two conditions, there may be valid reasons for low or no energy consumption such as the premise being vacant, the meter being installed on seasonal load such as cabins, sprinklers, or ballparks, or the customer may be disconnected at the transformer or ahead of the meter. With AMI, the diagnostic and analytical tools available are estimated to eliminate 2,550

field trips (approximately 60%) based on the Company's 2015 total of 4,257 orders of this type. This estimate is in alignment with Northern States Power – Minnesota, where analytics are performed in a manual method but with a different AMR system than at Public Service.

- **Reduction in customer equipment problem outages:** There were 2,450 work orders issued for customer equipment problems in 2014 in Public Service's territory, with an average cost per field trip of $129. Remote read access to meters will enable the Company to determine if an outage exists on the Company side of the meter. This ability is expected to significantly reduce costs associated with field trips that are not associated with company equipment problems. For this analysis, the Company again benchmarked with Ameren Illinois. Although Ameren estimated a 90% benefit, Public Service conservatively estimated a 50% reduction in such field trips.
- **Reduction in "Okay on Arrival" outage field trips:** The Company averaged approximately 7,900 field trips per year due to outage calls that are found to be "Okay on Arrival" between years 2012 and 2015. In developing an estimate for this benefit, the Ameren Illinois AMI Business Case was referenced and several utilities were consulted for their estimates or experience with this metric. We found that estimates ranged from 10% (Ameren Missouri) to virtually 100% (Ameren Illinois). Duke Energy shared its experience as a percentage of the meter population, 0.25% (2,500 orders per million meters). Others stated a benefit was

realized but had no quantifiable data readily available (PECO and Southern Company – Georgia Power). From this varied information, Public Service has estimated a 50% reduction or approximately 4,000 avoided "Okay on Arrival" outage field trips due to better data through AMI.

- **Reduction in field trips for voltage investigations:** Averaging the number of investigations over the years 2011 through 2014, the Company expects a reduction of approximately 1,700 field trips, or 60%, due to voltage investigations that will be able to be completed remotely. This estimated benefit was not benchmarked outside the Company but was internally developed in collaboration with Distribution Operations management.

Q. PLEASE DESCRIBE THE ANTICIPATED BENEFITS FOR THE CUSTOMER RELATED TO IMPROVEMENTS IN CUSTOMER CARE.

A. Benefits of AMI are expected to include reduced call volumes to Public Service from customers, and a reduction in the Company's back-office costs related to customer accounts. Public Service anticipates that these improvements in customer care will provide financial benefits beginning in 2019 as shown on Attachment REB-1. Based on 2015 Public Service call volumes related to meter readings and bill inquiries, the Company estimates an annual reduction of approximately 43,000 customer calls.

The Company also expects a reduction of approximately 73,000 manually handled transactions and associated back office expenses related to missed meter reads, stopped meter reads, high/low billing exceptions, and other billing exception validations performed. These inputs were used in the benefits included in Attachment REB-1. The estimated reduction of customer calls and manual transactions was developed internally. These operational benefits are considered customer benefits because the efficiencies gained will contribute to customer satisfaction, and the financial benefits gained indirectly benefit the customer through impacting the Company's cost of service to our customers.

Q. ARE THERE ADDITIONAL BENEFITS THAT CUSTOMERS WILL REALIZE AS A RESULT OF AMI INSTALLATION?

A. The timely reporting by the AMI meters of specific conditions in need of evaluation will allow the Company to correct these conditions more quickly. The availability of this information will also enable Public Service to detect and reduce meter tampering and energy theft, and to differentiate those instances more quickly from dead and malfunctioning meters. The benefits associated with meter tampering and energy theft are expected to begin providing quantifiable benefits in 2019. The Company has benchmarked this estimate with the Ameren Illinois AMI Business case and aligned its estimate to a conservative 0.25% gain in residential and small commercial customer revenue due to these added capabilities of AMI meters. This associated savings are included on Attachment REB-1.

Additionally, the Company will be able to remotely disconnect service on inactive residential and small commercial services. Based on 2015 data, and again considering Ameren Illinois's estimate of 56%, the Company estimates a

50% reduction in consumption on inactive residential meters using 2015 data. Based on a cost of $0.1296/kWh, this would equate to approximately 17,500,000 kWh saved. These inputs were used in the benefits included in Attachment REB-1.

Also, based on 2015 data, the Company estimates an 8% reduction in residential customer bad debt. This information is consistent with data provided to the Federal Energy Regulatory Commission based on other utilities' pre- and post-AMI deployment. These inputs were used in the benefits included in Attachment REB-1. These financial savings are considered customer benefits because they help avoid these costs of service to our customers.

There are also quantifiable economic benefits associated with the customers' reduced outage times. The utility industry recognizes that improved reliability from the customer perspective can be quantified. The Company identified dollar benefits by using estimated reduction in outage times due to the installation of AMI. The Company utilizes work done by the Lawrence Berkeley National Laboratory ("LBNL") to determine a dollar value associated with improving the customer's reliability. The work by LBNL uses customer average interruption duration index ("CAIDI") measures and values of outages based on customer class. CAIDI is the average time a customer is out of power when they experience an outage. Value to residential customers is based on their willingness to pay for improved service reliability, while value for commercial and industrial customers is based on change in expected net revenues associated with the improved reliability.

Different types of outages have different CAIDIs. For example, an outage impacting an entire feeder typically has the shortest outage time, while an outage impacting a single customer has the longest average time. This is due to the prioritization of outages impacting more customers over smaller outages.

Three categories of outages were considered in developing the estimated benefit:

1) Identification of nested outages on a storm day
2) Shortening the queue for single customer outage events
3) Providing faster response for a tap level event.

Improvement estimates in average outage durations in each of these categories were internally developed. Using the LBNL methodology for the three categories above and a total customer base of 1,347,385 resulted in an estimated combined outage benefit of $1.15 ($0.05 + $0.91 + $0.20, respectively) per customer. These inputs were used in deriving the benefits included in Attachment REB-1.

C. Qualitative Benefits

Q. PLEASE DESCRIBE THE ANTICIPATED NON QUANTIFIABLE BENEFITS OF THE AMI METERS' ADVANCED FUNCTIONS.

A. Public Service anticipates qualitative benefits in several areas, including:

- Improved customer choice and experience, leading to customer empowerment and satisfaction;
- Enhanced distributed energy resource integration;
- Environmental benefits of enhanced energy efficiency;

- Improved safety to both customers and Public Service employees;
- Improvements in power quality.

Q. PLEASE DESCRIBE THE CUSTOMER SATISFACTION BENEFIT.

A. AMI meters can be configured to measure, store and report peak demand and energy usage at selected time intervals. Together with appropriate web portals and smart phone applications, rates and programs, that information will empower customers to make better informed decisions on their energy usage. In addition, AMI will enable the Company to develop and offer additional rates and programs to meet our customers' particular usage profiles and needs.

Further, AMI will support a better utility experience for our customers. Because of the two way communication, the Company will be able to enhance customer assistance by remotely accessing the meter to provide information or address customer concerns without the delay of scheduling a Company representative to visit the customer's premise and meter. Additionally, as discussed in this testimony, the ability to detect an outage and monitor system voltages will benefit the customer through improved service quality.

In the event an AMI meter experiences a failure, it will either report a diagnostic error or discontinue communicating to the head-end application. When that occurs, the Company is quickly made aware of the malfunction at a specific location, as compared to the current system that only allows the Company to gain some failure information with its monthly bill read. This efficiency will minimize the time a customer's bill may need to be estimated and improve accuracy of the bill, as well as reduce customer frustration with metering issues.

In addition, the Company currently has no specific information for individual customer outages. Thus when a customer experiences multiple outages, four or more within a 12-month period, the Company analyzes potential solutions without much visibility into the specific events. AMI meters have the ability to record the time and duration of each individual outage, and the Company's ability to access that information increases the potential for the Company to create solutions for these customers.

While energy savings and reduced customer service costs can be and are estimated in our analysis, as Company witness Mr. Hancock explains in more detail, it is not possible to quantify the associated customer empowerment and customer satisfaction benefits.

Q. PLEASE DESCRIBE THE ENHANCED DISTRIBUTED ENERGY RESOURCE INTEGRATION BENEFIT.

A. As previously discussed, AMI will provide more timely data on the flow of energy to and from our customers. This functionality better supports those customers with distributed energy resources ("DER"). With this load flow information, and with voltage, current, and power quality data provided from AMI to ADMS, system operators will be enabled to optimize grid performance even with additional DER on the system.

Q. PLEASE DESCRIBE THE POTENTIAL ENVIRONMENTAL BENEFITS OF ENHANCED ENERGY EFFICIENCY.

A. AMI is expected to result in greater energy efficiency by the customer and the Company. As previously stated, AMI will provide the customer more information on energy usage and will enable the Company to offer additional time based rates or other offerings that allow more customer choice in controlling their energy usage and costs. To the extent these energy efficiency gains reduce the need for generation, they can contribute to lower energy emissions.

Q. PLEASE DESCRIBE THE SAFETY BENEFITS OF AMI.

A. AMI enables the meters to be read, disconnected and reconnected, and enables remote diagnostics of the customer's service, thereby minimizing safety risks of Company representatives. While AMR meters can do some level of automated reading, they cannot minimize meter diagnostic and connect/disconnect visits to the same extent as AMI meters. AMI provides several remote functions that eliminate or minimize the need for the Company to visit the meter, which minimizes the intrusiveness to the customer and potentially reduces safety concerns of unknown people accessing their property. Reducing these visits also reduces employee safety risks associated with customer pets and traversing unfamiliar properties. The ability to remotely disconnect service also supports customer safety by allowing the Company to potentially disconnect in an emergency situation more quickly than dispatching a truck to perform a disconnection of service.

Q. PLEASE DESCRIBE ANTICIPATED IMPROVEMENTS IN POWER QUALITY FROM AMI.

A. AMI will monitor and provide power measurement and voltage data at more points within the distribution system, which will be used in load flow and IVVO calculations to enable improvements in power quality. In other words, better voltage regulation reduces such situations as power flickers that may not amount to an outage, but may interfere with customers' homes or businesses. Additionally, timely power outage and restoration will enable improved outage management and contribute to improved power quality to our customers overall.

B. <u>Costs</u>

Q. WHAT WILL BE THE PRINCIPAL COSTS ASSOCIATED WITH THE IMPLEMENTATION OF AMI?

A. As identified in Attachment REB-2, the principal cost for implementing AMI will be the capital costs associated with the meters themselves, their installation, and vendor project management.

Q. HOW DID THE COMPANY DEVELOP ESTIMATES FOR THESE COSTS?

A. The Company developed estimates of these costs through a combination of internal costs and indicative costs from an RFx sent to four AMI vendors. Meter costs and AMI Vendor Project Management used in our modeling were derived from the responding vendor averages. Meter installation costs are a combination of vendor supplied pricing and internal Company costs. More specifically:

- **<u>Cost of AMI meters:</u>** Estimated costs provided from each vendor for residential and commercial type meters were separated into two categories, residential and commercial. Residential meters included meter form types 1, 2, and 12. Commercial meters included meter form types 5, 6, 9, and 16. In each of the categories for each vendor, the total price of each category was averaged by the number of meters in that category, and the results of each category were then averaged across all responding vendors to arrive an overall per unit cost used in the CBA. The resulting meter per unit cost of $107.55 used in the CBA includes estimated taxes and associated material, meter seals, and meter rings.

- **Cost of meter installation services:** Costs of residential meter installation services used in the CBA constitute the average cost provided from the responding vendors, which is $17 per meter. Only two of the three vendors provided estimated pricing for commercial meter installation services. When evaluating the costs provided for commercial meters, the Company determined that the vendor information did not provide sufficient detail to determine if the vendors met the Company's required installation procedures. As a result, a weighted average of the Company's present contractor installation costs for commercial meters of form type 16 ($29), and first set credit values for commercial meters of form types 5, 6, and 9 ($42.72) were weighted proportionally to arrive at a per unit commercial meter installation cost of $34.51. A weighted average of residential and commercial meter installation cost of $18.08 per meter was used as input to the CBA.

We note that meter installations will not occur until 2018. The 2017 capital meter installation costs in the CBA are for field installation tools to be used in meter deployment.

- **Cost of AMI vendor project management:** The cost of approximately $8.5 million over year 2018 to 2021 is the average pricing provided by respondents to the RFx. In addition to project management, this cost estimate includes training, integration assistance, and system testing.
- **Contingency costs:** As noted in my Attachment REB-2, Public Service has developed contingency amounts for the meters, installation, and vendor management costs. Because a final vendor has not yet been selected, costs associated with AMI implementation are the Company's best effort at accurate forecasting, and the Company believes the selected contingency is reasonable. Contingency amounts for meters (8%) and AMI vendor project management (15%) are based on the pricing ranges provided in the RFx vendor responses. The contingency for meter installation (10%) is based on installation options and procedures dependent on meter types.

These capital cost items are included in the cost-benefit analysis described in the Direct Testimony of Company witness Mr. Hancock. Taken together, Public Service estimates that the overall per meter cost is likely to be in the range of $194 to $250. The Company assumed $250 per meter in the CBA in an effort to be conservative. This cost includes estimated capital and O&M

costs associated with meters, meter installations, FAN, project management, project labor, IT integration, and contingencies.

Q. PLEASE DESCRIBE THE RFx PROCESS IN MORE DETAIL.

A. A cross functional team of employees from multiple business areas developed an RFx related to AMI, FAN, and distribution automation. The business and IT areas that were represented on the team included Meter Performance and Standards, Sourcing Services, Distribution Engineering, Business Solutions, Customer Care, Telecommunications Engineering, and Enterprise Architecture. The RFx was sent to SilverSpring Networks, Landis+Gyr, Elster, and Itron. All vendors with the exception of Elster provided a response. As part of the RFx, potential vendors were asked detailed technical questions regarding each of their individual AMI technology, including but not limited to the following topics:

- The technical standards their products are built to;
- Explanation of their standards-based philosophy and vision;
- Specific technical detail related to AMI, the FAN communication and distribution automation functions;
- The compatibility of their product with other components in the AGIS initiative; and
- Pricing information on meters and associated installation costs, FAN devices, head-end applications, project management and other support, and licensing costs.

The internal development team identified earlier in this answer evaluated the responses, and the Company used some of the information from the RFx for inputs in the Company's CBA, such as AMI meters, residential meter installation services, head-end application and its associated annual recurring fee, and vendor professional services which include project management, training, and network design.

Q. WILL THERE BE OPERATIONS AND PERSONNEL COSTS ASSOCIATED WITH THE IMPLEMENTATION AND ONGOING OPERATION OF AMI?

A. Yes. As noted in Attachment REB-2, there will be capital and O&M costs related to AMI operations and personnel for staffing the deployment of AMI and post-deployment staffing. The costs associated with project employees are based on typical Company wages, and contractor costs are costs of contractors at estimated wage scales. The personnel associated with the AMI Operations categories and estimated costs in Attachment REB-2 are:

- Metering Operations includes metering supervisor and meter engineering positions;
- Operations includes AMI analyst and project manager positions;
- Xcel Labor includes billing analyst and inventory support positions (this category has 2016 capital costs allocated and represents 43% of planned business RFP costs of requirements gathering); and
- Contract Labor, which includes billing, scheduling, administrative contractors and costs for electrical and general repair contractors

There will be O&M rental costs for warehouse space to support the staging of new meters and processing of removed meters. The estimate for this cost is based on internal estimates of 35,000 square feet at a cost of $28 per spare foot per year for two years. It also includes $230,000 for modifications, IT needs, and office furniture. These costs are included in the CBA discussed in the Direct Testimony of Company witness Mr. Hancock.

Q. ARE THERE OTHER O&M COSTS ASSOCIATED WITH THE INSTALLATION OF THE AMI METERS?

A. Yes, as noted in Attachment REB-2, O&M costs will include costs related to the development and issuance of the AMI request for proposals, and disposal of old meters. The AMI specifications and RFx development costs are associated with the wages and expenses of an identified cross-functional internal team. Costs for meter disposal are estimates that include sorting, removal of batteries as needed, and separation of encoder receiver transmitter ("ERT") modules from the AMR meters. The O&M costs for the AMI request for proposals, as well as the disposal of old meters were used in the cost-benefit analysis discussed in the Direct Testimony of Company witness Mr. Hancock.

Q. IS PUBLIC SERVICE ASSIGNING A CONTINGENCY AMOUNT FOR THESE O&M COSTS?

A. Yes. As noted in Attachment REB-2, Public Service has developed a 10% contingency amount for the O&M costs related to AMI operations and personnel. The 10% contingency for these items is an estimate. These inputs were used in the cost-benefit analysis discussed in the Direct Testimony of Company witness Mr. Hancock.

V. ALTERNATIVES

Q. DID PUBLIC SERVICE CONSIDER ALTERNATIVES TO AMI METERS?

A. The alternatives to AMI meters are to continue with the existing AMR meters or return to non-AMR, manually read meters. As part of the alternative of continuing with existing AMR meters, we considered the adoption of the AMR meter that would provide TOU and load profiling functionality described earlier. Although we may be able to provide customers more choice of time based rates with these meters, it is not viable to continue to utilize AMR technology long-term because it does not provide the timely two-way communication of data and other associated customer and Company benefits of AMI. Additionally, AMR meters have been discontinued from production by at least one of the Company's vendors to date. Finally, reverting to manual meters is not viable because they also lack the ability to provide timely two-way communication and the other benefits of AMI meters as described above.

Q. WHAT IS THE CONSEQUENCE OF NOT IMPLEMENTING AMI METERS?

A. The Company would continue to install and maintain AMR meters to provide billing reads for our customers. As the AMR system ages and approaches the end of its designed life expectancy and replacements are needed, the Company will continue to install AMR meters with aging technology. Over the next 20-years it is uncertain that meter manufacturers will continue to support AMR technology as it ages and as utilities continue to replace it with AMI technology as the predominant standard in the industry. Therefore, staying with AMR meters would not only make these assets more difficult to repair and replace with like-kind meters, but also would jeopardize the Company's ability to provide increasingly standard levels of service and technologies to its customers.

Q. WHY SHOULD THE COMPANY BEGIN INSTALLING AMI IN 2018 INSTEAD OF WAITING A FEW MORE YEARS?

A. AMI will be an integral part of the AGIS initiative, and as described throughout this testimony, AMI supports its objectives: (1) operators have more visibility into the system; (2) customers are able to access more information; and (3) future products and services are enabled through technology. Delaying AMI would leave the Company with less insight into the functioning of the distribution system, less up-to-date system data, and more limited customer services into the future. Additionally, the Company believes that AMR technology is stagnant and will not be supported in the long term. Finally, as more utilities adopt AMI technology the Company will fall behind industry standards.

Q. WILL PUBLIC SERVICE OFFER CUSTOMERS AN ALTERNATIVE TO ADOPTION OF ADVANCED METERS?

A. Yes. Consistent with programs offered in other states and by other utilities, the Company will develop and offer an AMI opt-out program at the time of meter deployment in 2018. The program will provide an option to our customers to have a non-AMI digital meter installed and have it manually read on a monthly basis for billing purposes.

Q. AT WHAT RATE DOES PUBLIC SERVICE ANTICIPATE CUSTOMERS WILL OPT OUT OF AMI METERS (IF AT ALL)?

A. Public Service estimates that less than 0.5% of Public Service customers will opt out of advanced metering. This assumption, which is incorporated into Public Service's CBA as discussed by Company witness Mr. Hancock, is based on an Electric Light & Power article[2] citing opt-out rates experienced by other utilities who have implemented AMI. In an informal survey, utilities that provided data have experienced even lower opt-out rates.

Q. WHAT ARE THE PRIMARY REASONS CUSTOMERS TEND TO OPT OUT OF AMI METERS?

A. The primary reason customers request an AMR or AMI meter be removed is discomfort with the radio frequency used to communicate to or from the meter. A non-AMI meter will not be equipped with any communications module. With this solution, the opt-out customers will be able to engage in TOU rates. However, because the meter will be read once a month, the customer will not have the ability to view more frequent energy information since the previous manual reading. In addition, the installation of the new meter and continued need for manual field trips to read meters comes at a cost. Therefore, it is common for opt-out programs to charge the customers who opt out for the costs that will be incurred to serve them.

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[2] Source: Electric Light & Power article, Smart Meter Policies explained" by Chris King. http://www.elp.com/articles/powergrid_international/print/volume-17/issue-11/features/smart-meter-opt-out-policies-explain.html.

Q. WHAT DOES PUBLIC SERVICE PROPOSE TO CHARGE CUSTOMERS WHO OPT OUT OF AMI?

A. The Company plans to charge customers who choose to opt-out of AMI deployment with the one-time cost of a non-AMI, electronic meter capable of measuring TOU energy consumption and recording load profile in 15-minute intervals. At this time, the Company estimates the total cost of the new non-AMI meter will be approximately $200. Customers will also incur a monthly fee of approximately $11, which covers manual meter reading and handling charges. The actual costs per opt out customer will be determined in the Company's next Phase II rate case.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE ALTERNATIVES TO IMPLEMENTING AMI METERS?

A. AMR provides limited benefits when compared to AMI. AMI will provide customers more timely energy information and more control over how and when they use energy in their homes and businesses. It will enable the Company to provide an improved customer experience over AMR when addressing customers' concerns with their meter reading, billing, power outages, quality of service, and connections of service. Further, AMI is much more than a meter reading technology: it is an integral component of AGIS and contributes to important operational enhancements made possible with ADMS and IVVO with integration of data not available through AMR. Although AMI offers many more customer benefits than AMR, our opt-out program plans will also provide customer choice for those who choose not to have all the features that AMI provides.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Russell E. Borchardt

As the Director, Business Operations, I am responsible for providing leadership and technical expertise in the operations and engineering of Xcel Energy's electric and gas metering organization. My duties include providing strategic direction and overall management of Meter Engineering, Performance & Standards and Field & Shop Metering areas. This includes oversight of gas and electric meter population performance; testing, installation and removal of meters; directing the development of metering standards and evaluation of metering technologies; management of practices, procedures, and policies related to metering; development and implementation of strategic business and workforce planning.

I began my career with an Xcel Energy Inc. ("Xcel Energy") subsidiary, Northern States Power Company ("NSP") in 1981. I held engineering positions in Service Policy and Substation Engineering and Construction prior to accepting a position in Electric Metering in 1987. From 1987 – 2002, I held technical and management positions in the areas of meter engineering, operations, and project management. In addition to performing engineering services and management of departmental operations during this time, I evaluated new metering technologies and developed technical specifications and functional requirements for AMR to be implemented at NSP. Subsequently, I managed the engineering and directed project operations to deploy a radio frequency, fixed network AMR system throughout Minnesota, South Dakota and North Dakota.

In 2002, I left employment at Xcel Energy and accepted a position at Salt River Project ("SRP"). While employed at SRP from 2002 to 2010, I managed meter engineering and field operations of the Metering and Field Customer Services department. During this tenure, I directed the technology evaluation, engineering, deployment, and operations of one of the first wireless AMI networks to be deployed.

In 2010, I returned to Xcel Energy and managed the System Protection area with Substation Construction and Maintenance until accepting the role of Business Operations Director in the electric and gas metering organization in 2012.

I am an Electrical Engineering graduate of the University of Minnesota, and I have been a registered professional engineer since 1986. I have been an active participant on EEI and AEIC meter and service committees for over 25 years.